

Response to Ofgem Consultation on ‘Getting more out of our electricity networks by reforming access and forward-looking charging arrangements’

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About EPUKI

EP UK Investments (EPUKI) is a UK energy company, primarily focusing on power generation from conventional and renewable sources.

EPUKI represents the UK interests of Energetický a průmyslový holding (EPH), a leading Central European energy group that owns and operates assets in the Czech Republic, the Slovak Republic, Germany, Italy, the UK and Hungary. EPH is a vertically integrated energy utility covering the complete value chain ranging from highly efficient cogeneration, power generation, and natural gas transmission, gas storage, gas and electricity distribution and supply. The companies in the group employ nearly 25,000 people.

EPH is the largest supplier of heat in the Czech Republic, the biggest electricity producer and the second biggest electricity distributor and supplier in Slovakia and ranks as the second biggest lignite producer in Germany. It is also an operator of a robust transmission network in Europe, a key transporter of Russian natural gas to Europe and the biggest gas distributor in Slovakia. In total it has 22 GW of heat and power capacity including coal, lignite and renewables.

EPH entered the UK market in 2015 through the purchase of Eggborough Power Limited. In 2016, EPH purchased Lynemouth Power Limited, the owner and operator of a 420 MW coal-fired power station in Northumberland which holds a Contract for Difference for full biomass conversion. In September 2017 EPH acquired Langage and South Humber Bank combined cycle gas turbine (CCGT) power stations from Centrica plc, with a combined capacity of 2.3 GW. EPUKI continues to actively pursue other acquisitions and new build opportunities in the UK electricity market, including the Eggborough and King's Lynn B CCGT projects.

General comments

EPUKI welcomes the opportunity to respond to Ofgem's consultation on reforming access and forward-looking charges on electricity networks. In general, we are supportive of the areas which Ofgem has identified for review and agree that most of these should be progressed through a Significant Code Review (SCR).

EPUKI has experience operating power stations connected to both the transmission and distribution network and our response is written from the perspective of power generation. We consider that the current suite of access and charging arrangements applying to the transmission network are generally fit for purpose and have only recently been reviewed. However, we do consider that there is scope for a review of arrangements relating to the distribution network. We wish to see greater consistency between the access and charging arrangements at distribution and transmission level. We consider that the current arrangements create perverse incentives to connect power generation to the distribution network and encourage companies to seek opportunities to avoid using the transmission

network where this would otherwise be the logical choice. We are concerned that this may be leading to inefficient outcomes and increasing costs to consumers.

Specific comments

Question 1: Do you agree with the case for change as set out in this chapter? Please give reasons for your response, and include evidence to support this where possible.

We agree with the case for change. In particular, we consider that the distinction between generation connected to the distribution and transmission networks is no longer applicable due to the degree of export from some parts of the distribution network. The current charging arrangements do not reflect this shift in network usage and are providing an unjustifiable incentive for some projects to connect to the distribution rather than the transmission network. We consider that the proposed review of access and forward-looking charges presents an opportunity to address the discrepancies which exist based on the voltage at which a generator is connected.

Question 2: Do you agree with our proposal that access rights should be reviewed, with the aim to improve their definition and choice? Please provide reasons for your response and, where possible, evidence to support your views.

We consider that a review of access rights may identify opportunities to make more efficient use of network capacity in a way which meets the requirements of users. However, in general we consider issues relating to charging to be a greater priority as this is driving the greatest distortion.

Question 3: Specifically, do you have views on whether options should be developed in the following areas as part of a review? Please give reasons for your response, and where possible, please provide evidence to support your views:

a) Establishing a clear access limit for small users, with greater choice of options (as considered under b) and c) below) above a core threshold – do you agree with our proposal in paragraphs 3.5-3.10 that this should be considered? Do you have views on how a core threshold could be set?

No EPUKI comment.

b) Firm/non-firm and time-profiled access – do you agree with our proposal outlined in paragraphs 3.15-3.21 that these options should be developed?

Firm/non-firm access

We consider that introducing financially firm access rights at distribution would be desirable. We do not consider that introducing non-firm access at transmission is a priority at this time. It is important that any access arrangements for small distributed generation using the transmission network should be equivalent to those for larger users so as to create a level playing field and avoid unintended consequences.

Time-profiled access

We are not convinced that time-profiled access is a reasonable approach for power generation as the nature of many technologies is that they could export to the network at any time in response to market conditions and networks would need to be sized accordingly.

c) Duration and depth of access, discussed in paragraph 3.25-3.32 - would these options be feasible and beneficial?

Duration of access

We consider that financially firm evergreen access rights are crucial to provide certainty for investment in large-scale power generation. From a power generation perspective, asset lifetime can be affected by a number of factors and, if fixed duration access rights were introduced, there would

need to be absolute certainty that additional access rights could be obtained after the fixed term period. We therefore agree with Ofgem that encouraging trading of access rights and developing shorter term forms of access are preferable to introducing fixed-term, long term rights. Ofgem must be clear that any consideration of fixed term access rights will not affect existing users who will have made investment decisions on the basis that their existing access rights are evergreen.

Short term access already exists on the transmission network as Short Term TEC and Limited Duration TEC. However, there are limits to how useful these products are because they cannot be obtained until after the relevant Charging Year has begun and there is no certainty as to whether access will be granted. As a result, existing generators are likely to favour an evergreen access product where there is any possibility that they may be operational in a future year. We therefore consider there may be merit in a shorter term access product which could be secured up to several years in advance.

Depth of access

We agree that it would be overly complex to develop local access rights and we are not clear how these could be effectively enforced. We agree that a review of DUoS would be a more appropriate way to incentivise efficient use of distribution networks.

d) At transmission or distribution in particular, or are both equally important – as discussed in this chapter?

As discussed above, we consider that changes at distribution are likely to be a higher priority than those at transmission level.

Question 4: Do you agree with the key links between access and charging we have identified in table 1? Why or why not? Do you think there are other key links we have not identified? Where possible, please provide evidence to support your views.

It is important that the charging arrangements accompanying new access products do not incentivise perverse outcomes. For example, it may not be appropriate to offer lower charges to users with less firm access rights if the risk of constraints in an area is low as this would incentivise most users in this area to opt for less firm rights. Short-term access rights should also be priced in such a way that a user is not incentivised to obtain a series of short-term rights equivalent to a longer-term period of access but at a discount.

Question 5: Do you agree with our proposal that targeted areas of allocation of access should be reviewed? Please give any specific views on the areas below, together with reasons for your response. Where possible, please provide evidence to support your views:

a) Improved queue management as the priority area for improving initial allocation of access, as outlined in paragraphs 3.41-3.44?

We agree that improved queue management would be desirable at distribution level.

We also note that issues may be arising at transmission level as a result of potential large new build power stations aligning their contractual connection dates around the start of the same Capacity Market Delivery Year. This may make it difficult for National Grid to accommodate outages to connect all the projects in an area and is having a knock-on impact on the connection dates offered to projects. However, as all these projects are not likely to proceed (as not all will obtain a capacity agreement) then a degree of queue management would be required to accommodate projects which do go ahead. A review of the options available to National Grid to plan in these circumstances would be desirable.

b) Not to consider the potential role of auctions for initial allocation of access as part of a review at this time, as discussed in paragraph 3.44?

We agree that auctions for initial allocation of access should not be considered.

c) To review the areas outlined in paragraphs 3.45-3.48 to support re-allocation of access?

We do not support the concept of use it or lose it for transmission access rights. There are many factors which may mean that a generator is temporarily not making full use of its access rights (eg. mothballing for economic reasons) and it would not be appropriate to remove its access rights with no certainty that they can be reobtained.

A mechanism to allow reallocation of access rights on a temporary or enduring basis is desirable. Temporary TEC Exchanges already exist at transmission level. However, we understand that the calculation of exchange rates means that in reality there is little scope to utilise this option unless the two sites are located on the same part of the network. The exchange rate mechanism may therefore need to be reviewed.

Question 6: Do you agree that a comprehensive review of forward-looking DUoS charging methodologies, as outlined in paragraphs 4.3-4.7, should be undertaken? Please provide reasons for your response and, where possible, evidence to support your position.

Yes, we agree that a review of the CDCM and EDCM charging methodologies is necessary.

The current CDCM is too simplistic and the credit applied to generation may not always be reflective of actual network conditions. This could be encouraging generation to locate at lower voltages rather than at EHV. We would therefore support a charging regime at lower voltages which is more granular and more consistent with the charging structure adopted at higher voltages. Ofgem's proposed zonal approach may be a sensible solution.

While we consider a review of CDCM to be a higher priority, there may also be merit in reviewing aspects of the EDCM methodology on the basis that this does not provide sufficient transparency or predictability in charges for EHV users. When assessing potential investments in new EHV generation projects there is no clear way to obtain certainty about the level of use of system charges that will be incurred due to the location-specific nature of the charges. Furthermore, as Ofgem recognises, EHV charges can be subject to year on year variations. This lack of transparency and predictability acts as a barrier to investment. We therefore consider that Ofgem should review whether longer-term forecasts of charges for EHV connections in an area can be provided.

Question 7: Do you agree that the distribution connection charging boundary should be reviewed, but not the transmission connection boundary? Please provide reasons for your response and, where possible, evidence to support your position.

We consider that the current transmission connection boundary is fit for purpose. There may be a case for reviewing the connection boundary at distribution level, but as Ofgem recognises this is likely to be dependent on the signals sent by use of system charges. More closely aligning the connection boundary at transmission and higher distribution voltages would avoid any perverse incentive to locate at one level rather than the other.

Question 8: Do you agree that the basis of forward-looking TNUoS charging should be reviewed in targeted areas? If you have views on whether we should review the following specific areas please also provide these:

a) Do you agree that forward-looking TNUoS charges for small distributed generation (DG) should be reviewed, as outlined in paragraphs 4.19-4.23?

Yes, we agree that this review is necessary. There is no longer a clear distinction between embedded generation's use of the distribution and transmission networks. The threshold at which generators are expected to hold a Bilateral Embedded Generation Agreement and pay generation TNUoS is currently set at 100 MW. This threshold is entirely arbitrary and does not reflect the cumulative impact of several embedded generators locating in a part of the distribution network. A large number of GSPs export to the transmission network and it is therefore not appropriate that the generators located in these parts of the distribution network do not contribute to the costs of the transmission network.

We agree that it would be most appropriate to charge embedded generators TNUoS based on their capacity rather than generation over the triad because this would more accurately reflect the potential for export from the wider range of technologies using the network (eg. renewables) and be consistent with the approach applied to generators connected directly to the transmission network.

We agree that the contractual relationship to charge TNUoS to distributed generation requires consideration. For administrative simplicity and transparency, there may be a case for reducing the threshold above which generators must hold a BEGA. For generators below this threshold, the DNO could act as an agent for the generator.

b) Do you consider that forward-looking TNUoS charges for demand should be reviewed, as outlined in paragraphs 4.24-4.27? Please provide reasons for your response and, where possible, evidence to support your position.

Basing demand TNUoS on triad periods may be encouraging generation to locate behind the meter and we consider that this is an area which could be reviewed. It is not appropriate that behind the meter generation, which can often only reduce a consumer's use of the network for a limited period, should be used to reduce charges for network usage from which a consumer benefits throughout the year. The lack of visibility about how such generation is utilised is also likely to make grid management more difficult and we consider that Ofgem should ensure that there are not unjustifiable incentives to locate behind the meter.

Question 9: Do you agree that a broader review of forward-looking TNUoS charges, or the socialisation of Connect and Manage costs through BSUoS at this time, should not be prioritised for review? Please provide reasons for your response and, where possible, evidence to support your position.

We agree that a broader review of forward-looking TNUoS charges is not a priority at this time given that Project TransmiT has only recently been concluded and we have not identified any major defects with the current model. However, we would welcome greater clarity on the future application of the €2.50/MWh cap on average generator transmission charges in the light of Brexit and the work on the Targeted Charging Review as this represents a major risk to the overall level of generation transmission charges.

We consider that there are serious issues arising from socialisation of constraint management costs which require urgent review and these are discussed in our response to question 10.

Question 10: Do you agree that there would be value in further work in assessing options to make BSUoS more cost-reflective, and if so, that an ESO-led industry taskforce would be the best way to take this forward?

We have serious concerns about the current application of BSUoS. The level of BSUoS in some Settlement Periods and the way in which it is targeted is creating perverse signals. In particular, we have identified the following issues:

- The way in which costs are allocated to different parties means that some parties are unduly benefitting from constraints, whereas others which are actively contributing to managing system issues are penalised by high BSUoS costs. For example, when a wind farm is constrained off the system it may benefit through constraint payments, whereas a generator which is generating as planned or has been offered on to help balance the system has to bear the costs of these constraints. BSUoS costs are increasingly high in some periods, with BSUoS prices reaching in excess of £20/MWh in recent months. Typically this has been overnight, but increasingly this is occurring during the daytime. We are concerned that as the level of renewables connected to the network increases, spikes in BSUoS prices during the day will become more common. In some periods, wind farms will have profited from being constrained off while conventional generators which have been required to generate in these periods to help balance the system have made a loss as a result of high BSUoS prices that are not known until after the event.
- It is difficult for market participants to predict BSUoS prices with any accuracy due to their volatility and the error margin in National Grid's BSUoS forecast can be significant. This creates

substantial risk and participants may be including a BSUoS risk premium in their pricing, ultimately driving up costs to end consumers.

- Excessively high BSUoS prices do not send logical signals to generators. For example, a unit which is offered on in the Balancing Mechanism during a period of high BSUoS could seek to recover the anticipated BSUoS price in its offer price, but would end up bearing this higher Balancing Mechanism cost in its BSUoS charge, leading to a spiral of rising Balancing Mechanism and BSUoS prices. Given the difficulties in accurately forecasting BSUoS and the risks of being subject to punitively high BSUoS prices, generators may be encouraged to make themselves unavailable in periods of particularly high BSUoS even though these generators are best placed to help balance the system.
- Distributed generation not only avoids paying BSUoS but also benefits from helping to reduce a supplier's BSUoS liability. This embedded benefit will increase as BSUoS prices increase. This provides an unfair advantage for generation located on the distribution network compared to that located on the transmission network and allows it, for example, to bid a lower price in the capacity market compared to transmission-connected generation. Many of these embedded generators will be exporting to the transmission network in some periods and contributing to system balancing issues, especially as their output is unpredictable and not visible to the System Operator. However, these generators are not contributing to the costs of the managing the network. We therefore consider that, as with TNUoS, there is now a clear case to charge BSUoS to distributed generation.

We therefore consider that a substantial review of BSUoS is required to provide more certainty to market participants. There are several possible improvements that could be made to the current arrangements. In any case, we consider that the BSUoS embedded benefit for distributed generation should be removed by charging BSUoS to gross rather than net demand. This would help level the playing field between distribution and transmission-connected generation.

In addition to this, our preferred solutions in order of preference for addressing the problems we have identified are as follows:

1. Charging BSUoS entirely to gross demand

EPUKI considers that BSUoS is primarily a cost recovery tool which does not send sensible signals to which a generator can react. EPUKI therefore considers that it should be treated in the same way as Ofgem intends to treat other residual charges and should be charged entirely to gross demand.

2. Fixing BSUoS for a year with 12 months' notice period

If BSUoS remains allocated to generation, we support the concept of fixing the BSUoS charge for a year with at least 12 months' notice. This would provide advance certainty to market participants as to the BSUoS charge that they will face in any Settlement Period and therefore prevent the unintended consequences of spiralling BSUoS prices described above. Furthermore, by averaging the BSUoS costs across a year, this will mean that all types of generation pay a share of BSUoS costs which is more reflective of their impact on the system. We therefore support the implementation of CMP250 and consider that Ofgem should approve this modification at the earliest opportunity. In this case, BSUoS should also be charged to embedded generation so that it is subject to the same charges as transmission-connected plant.

3. Reviewing the components and allocation of BSUoS charges

If Ofgem decides not to remove BSUoS from generation or fix it in advance, we consider that it should review which costs are recovered through BSUoS and how it is allocated between parties. For example, a pure cost recovery component (such as Black Start costs) does not send a sensible signal to which a generator can react and should not form part of BSUoS. There may also be merit in allocating the charge differently. For example, applying BSUoS to parties based on their Physical Notifications rather than metered generation would avoid the current situation whereby parties which are constrained off do not bear any of the costs of constraints but those who are offered on to help balance the system do.

We agree that an industry task-force should be established to consider these issues in more detail. EPUKI would wish to be represented on this group. It is crucial that any solution appropriately takes into account the views of all market participants rather than simply being devised by the System Operator.

We also note that interconnectors are currently exempt from paying BSUoS, which provides an unfair advantage to imported power compared to domestic generation. We consider that Brexit may present an opportunity to reassess whether interconnectors should pay BSUoS and TNUoS, which would level the playing field with domestic generation, and this should be considered as part of any review.

Question 11: What are your views on whether Ofgem or the industry should lead the review of different areas? Please specify which of SCR scope options A-C you favour, or describe your alternative proposal if applicable. Please give reasons for your view.

We consider that access rights are likely to be the element on which industry will be able to make greatest progress and this part of the review could therefore be industry-led. Furthermore, the more elements which are included in the SCR, the greater the risk that there will be a delay in the SCR process. We therefore consider it would be desirable to restrict the SCR to a narrower scope (ie. option A).

Question 12: Do you agree with our proposal to launch an ‘Option 1’ SCR for areas of review that we lead on? Please give reasons for your view.

In general, we consider that Ofgem should avoid by-passing normal industry processes and engagement in code modifications and therefore we agree that Option 1 is the preferred approach.

Question 13: Do you agree with the introduction of a licence condition on the basis described in paragraphs 5.11 and 5.12 and Appendix 5? Why or why not? Do you have any comments on the key elements set out in table 7 of Appendix 5a, or consider there are any other key elements which should be included? Please give reasons for your view.

We consider that the greatest benefit in introducing such a licence condition would be in ensuring that any review process meets a defined timetable.

Question 14: Do you have any comments on the draft wording of the outline licence condition included at Appendix 5b? Please give reasons for your view.

No EPUKI comment.

Question 15: What are your views on our indicative timelines? Do you foresee any potential challenges to, or implications of, the proposed timelines and how could these be mitigated?

No EPUKI comment.

Question 16: What are your views on our proposals for coordinating and engaging stakeholders in this work?

We agree that continued use of the Charging Futures Forum would be sensible. Expert groups are likely to be required to support this work, but by their nature these will exclude some parties. A high degree of transparency is therefore required by publishing papers in advance of expert meetings and accurate summaries of discussion after the meetings. There should also be other opportunities for stakeholders to submit written comments during the process.